NON-PUBLIC?: N
ACCESSION #: 9101020270
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Catawba Nuclear Station, Unit 2 PAGE: 1 OF 11

DOCKET NUMBER: 05000414

TITLE: Main Feedwater Pump Trip Due to Equipment Failure Resulting in a Reactor and Main Turbine Trip
EVENT DATE: 10/07/90 LER #: 90-013-01 REPORT DATE: 12/19/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 98

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: C. L. Hartzell, Compliance Manager TELEPHONE: (803) 831-3665

COMPONENT FAILURE DESCRIPTION:
CAUSE: F SYSTEM: SJ COMPONENT: XIS MANUFACTURER: C753
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On October 7, 1990, at approximately 1659 hours, with Unit 2 in Mode 1, Power Operation, and operating at 98% reactor power level, a Reactor (Rx) trip occurred due to low-low level in the 2D Steam Generator (S/G). The Reactor trip occurred after the 2A Main Feedwater Pump Turbine (CFPT-2A) tripped on indicated high discharge pressure which initiated a turbine runback. The Main Turbine ran back past its setpoint of 70% load; terminating at approximately 60% when the Rx tripped. Subsequent investigation of the event revealed that the CFPT-2A trip occurred due to an erroneous high discharge pressure signal which resulted from failed diaphragms in two of the three feedwater pump discharge pressure switches. Subsequent corrective actions included stabilizing the unit and replacing the defective pressure switches. This incident is attributed to an Equipment Failure. Additional corrective actions included review and investigation of the event to determine the root cause of the minor discrepancies noted during the post-trip review,

development of a Rx Trip report, and replacement of the failed pressure switches.

END OF ABSTRACT

TEXT PAGE 2 OF 11

BACKGROUND

The Condensate EIIS:SD! (CM) and Feedwater EIIS:SJ! (CF) Systems are designed to re-turn condensate from the condenser hotwells through the condensate polishing demineralizers and the regenerative feedwater heating cycle to the steam generators EIIS:HX! while maintaining proper water inventories throughout the cycle.

The entire CM system is non safety-related. The portions of the CF System that are required to mitigate the consequences of an accident and allow safe shutdown of the reactor are safety-related.

The CM System consists of three 50% capacity hotwell pump strainers, three 50% capacity hotwell pumps EIIS:P!, five 25% capacity condensate polishing demineralizers and associated regeneration equipment, two stages of low pressure feedwater heaters EIIS:EHTRS! (F and G), three 50% capacity condensate booster pumps, three stages of intermediate pressure feedwater heaters (C, D, and E), and piping EIIS:PSP!, valves EIIS:V!, and instrumentation. The cycle begins with the hotwell pumps taking suction from the condenser hotwell. During normal operation, two hotwell pumps will be operating with the third on standby. After the hotwell pumps, the condensate flows to the condensate polishing demineralizers. Normally, four of the five polishers will be in operation with the fifth on standby. Downstream of the condensate polishing demineralizers, the condensate is divided equally between the three condenser steam air ejectors (CSAEs) where it is used as a coolant in the CSAE inner and after condensers. All three ejectors are normally in service with each air ejector removing noncondensable gases from one of the three condenser shells. After the CSAE's the condensate flows in parallel through the gland steam condenser and the blowdown recovery heat exchangers. The condensate then passes through two stages of low pressure feedwater heaters to the suction of the condensate booster pumps.

During normal operation, two condensate booster pumps will be in operation with the third on standby. Downstream of the condensate booster pumps, the condensate passes through three stages of intermediate pressure feedwater heaters before combining with the 'C' heater drain pump flow and discharging to the suction of the feedwater pumps.

The CF System consists of two 50% capacity steam generator feedwater pumps, two stages of high pressure feedwater heaters (A and B), and piping, valves, and instrumentation.

Normally, both feedwater pumps will be operating with each pump handling half the feedwater flow. Downstream of the feedwater pumps, the feedwater passes through two stages of high pressure feedwater heaters to a final feedwater header where the feedwater temperature is equalized. The feedwater is then admitted to the steam generators through four steam generator feedwater lines, each of which contains a feedwater control valve and a feedwater flow nozzle.

Feedwater flow to the individual steam generators is controlled by a three element feedwater control system using feedwater flow, steam generator water level, and main steam flow as control parameters for steam generator feedwater control valves (2CF28, 2CF37, 2CF46, and 2CF55).

The Auxiliary Feedwater EIIS:BA! (CA) System assures sufficient feedwater supply to the steam generators in the event of loss of the CM/CF Systems, to remove primary coolant stored and residual core energy. The system is designed to start automatically in the event of loss of offsite electrical power, trip of both CF pumps, safety injection signal (SS), or low-low steam generator water level; any of which may result in, coincide with, or be caused by a Reactor trip. In addition, the CA System will supply sufficient feedwater flow to maintain the Reactor at hot standby for two hours followed by cooldown of the Reactor Coolant EIIS:AB! (NC) System to the temperature at which the Residual Heat Removal EIIS:BP! (ND) System may be operated.

The CA System consists of three auxiliary feedwater pumps; each powered from separate and diverse power sources. Two full capacity motor EIIS:MO! driven pumps are capable of supplying feedwater to two steam generators. These pumps will start automatically and provide the minimum required flow against a S/G pressure corresponding to the set pressure plus 3% accumulation of the lowest set main steam safety valve within one minute following initiation of the system. Initiation conditions are any one or combination of the following: 2 of 4 low-low level alarms in any 1 of 4 S/Gs, loss of all CF pumps, initiation of a SS, or loss of offsite power. In addition, a turbine EIIS:TRB! driven pump is capable of supplying feedwater to two S/Gs. This pump is driven from steam contained in either of the two S/Gs. The turbine driven pump will start automatically and provide the minimum required flow against a S/G pressure corresponding to the set pressure plus 3% accumulation of the lowest set main steam safety valve. This pump will start automatically on any one or both of the following conditions: 2 of 4 low-low level alarms in any 2 of 4 S/Gs; loss of offsite power.

Pressure Transmitters EIIS:XT! 2CFPT5080 and 2CFPT5081 monitor Feedwater Pump Turbine (CFPT) 2A discharge pressure. 2CFPT5080 supplies signals to pressure switches 2CFPS5080, 5081, 5084, and remote indicator EIIS:XI! 2CFP5080. 2CFPS5080 energizes a solenoid to valve 2CF-9 (CFPT 2A discharge check valve) on decreasing discharge pressure. 2CFPS5081 provides an input to the 2/3 trip logic on High-High Discharge Pressure for CFPT-2A. The other two inputs are provided by 2CFPS5082 and 2CFPS5083. These two pressure switches monitor discharge pressure directly and are not fed from 2CFPT5080. 2CFPS5084 provides a High Discharge Pressure Annunciator EIIS:ANN! Alarm. 2CFPT5081 provides computer analog input with a High Discharge Pressure Alarm.

EVENT DESCRIPTION

On October 7, 1990, Unit 2 was operating in Mode 1, Power Operation p at 98% Reactor power level.

At approximately 1658 hours, Control Room Operators (CROs) received the CFPT 'A' trip annunciator and immediately verified that the CFPT 2A had actually tripped on indicated high discharge pressure via their control board indications. CFPT 2B remained in service. Control Room personnel immediately referred to the Loss of Feedwater and entered the Load Rejection procedures, AP/2/A/5500/06 and AP/2/A/5500/03 respectively. The CROs recognized that a turbine runback was needed for the existing conditions.

After approximately 6-7 seconds, a main turbine/generator EIIS:GEN! runback initiated. At this time, CROs received Steam Generator (S/G) level deviation alarms and observed all S/G levels decreasing rapidly. CROs took manual control of CFPT 2B in an attempt to increase flows to the S/Gs but the pump was supplying maximum flow as all the main feedwater regulating valves were in the full open position. CROs dispatched a Nuclear Operator Technician (NOT) to investigate the CFPT 2A trip at its local control panel in the plant. In addition, CROs observed Reactor Coolant (NC) System T-AVE rapidly decreasing from 591 degrees F. To minimize the cooldown, CROs began isolating various steam drain valves. In addition, an operator was dispatched to startup the auxiliary electric boilers (AEB) to supplement the steam loads. The steam dump valves functioned properly in response to the runback and to control NC T-AVE. At approximately 1659 hours, 2D S/G reached its Low Low Level Reactor trip setpoint of 36.8% resulting in a Reactor and turbine/generator trip. The Reactor trip breakers EIIS:BKR! opened at 1659:00.183 hours. The turbine runback passed its 70% setpoint; terminating at approximately 60% load. Auxiliary Feedwater (CA) motor driven pumps auto started at 1659:58.105 hours, as expected. Subsequently, 2C S/G reached its Low Low Level setpoint resulting in an auto start of the CA turbine driven pump at 1659:58.921 hours, as its Low Low Level auto start logic was satisfied. All CA auto start valves functioned as expected. However, after review of the Transient Monitor System (TMS) data, it was discovered that flow to S/Gs C and D was delayed by approximately 15 seconds.

Control Room (C/R) personnel immediately referred to the Reactor Trip or Safety Injection procedure, EP/2/A/5000/01, to verify the plant properly responded to the trip and to assess plant conditions. Per guidance in EP/2/A/5000/01, they referred to the Reactor Trip Response procedure EP/2/A/5000/01A, since there was not a safety injection during the transient.

At approximately 1700:03 hours, a CF Isolation occurred as a result of the Reactor Trip and T-AVE dropping to less than 564 degrees F. All CF isolation valves functioned properly and CFPT 2B reduced to minimum speed, as expected. The minimum NC T-AVE was 545 degrees F.

At approximately 1712 hours, S/Gs levels had recovered enough that all Narrow Range (N/R) level indicators read greater than 5%. CROs then throttled CA flow in order to minimize the cooldown.

At approximately 1714 hours, CROs had successfully achieved acceptable S/G levels with NC T-AVE trending upward. At this point, they continued to follow the guidance in EP/2/A/5000/01A which referred them to the Turbine Generator Trip procedure, AP/2/A/5500/02, and provided additional guidance to prepare the plant for a fast recovery.

At approximately 1725 hours, CROs secured 2B and 2C Condensate Booster and 2B Hotwell Pumps.

At approximately 1728 hours, CROs had successfully achieved stabilized plant conditions in that NC T-AVE, NC pressure, and Pressurizer level were approximately 557 degrees F, 2230 psig, and 35% respectively. S/G N/R levels had not stabilized to approximately 62% but were trending upward.

C/R personnel continued to use EP/2/A/5000/01A for guidance in order to maintain stable conditions and prepare the plant for a Unit Fast Recovery per OP/2/A/6100/05.

At approximately 1847 hours, OPS personnel made the required NRC notification for the Rx trip.

At approximately 1945 hours, the Performance Rx Group began the investigation of the Rx trip.

On October 8, 1990, at approximately 0147 hours, the Instrument and Electrical (IAE) Group discovered the cause of the 2A CFPT trip was due to failure of 2 of 3 pressure switches which monitors pump discharge pressure. The pressure switches failed due to water infiltration due to a ruptured diaphragm.

At approximately 1639 hours, CROs placed 2A CFPT in service and secured 2B CFPT to allow IAE to replace the failed pump discharge pressure switches.

At approximately 2222 hours, CROs started 2B CA pump per PT/2/A/4250/06, CA Pump Head and Valve Verification Test, for Performance testing to determine if the pump's performance had been degraded.

On October 9, 1990, at approximately 0225 hours, CROs commenced a Rx startup (entered Mode 2, Hot Startup).

At approximately 0330 hours, CROs entered Mode 1 and commenced a Rx power escalation.

At approximately 0510 hours, CROs placed the turbine/generator on-line.

CONCLUSION

This incident is attributed to an Equipment Failure in that CFPT 2A tripped due to an erroneous high discharge signal initiating a turbine runback. Per a subsequent investigation of the trip, the root cause of the CFPT 2A trip was determined to be failure of the diaphragms of both 2CFPS5083 and 2CFPS5082 (CFPT 2A discharge pressure indication). The diaphragm failure allowed water to enter into the housing of each pressure switch, eventually short circuiting the component and satisfying the 2 of 3 trip logic on high feedwater pump discharge pressure. The pressure switches are manufactured by Custom Controls and are polymide

(Kapton) diaphragms. These type pressure switches have a higher than acceptable failure rate and had already been identified as the root cause of a similar incident which occurred at McGuire Nuclear Station in March 1989 (reference LER 370/89-02 Rev 0.) As a result of feedback from the Operating Experience Program (OEP), General Office (GO) Maintenance personnel had initiated a Design Study to identify applications of these components with unit trip potential. This study (CNDS-0194) was completed on April 30, 1990, and sent to Catawba's MES group. Upon receipt, MES personnel supplemented the results of the study with a walkdown and review of the physical layout of these applications to determine if additional concerns were raised. MES then initiated a Station Problem Report (SPR) CNPR-05122 to change out the polymide diaphragms with a more reliable stainless steel material. The SPR noted the unit trip potential. In addition, as an interim corrective action, MES submitted work requests which would be used to replace these pressure switches with the same model prior to a failure. Projects Services (PJT) supervision, who were aware of the failure history, processed the SPR as normal due to the fact that the urgency perceived from MES was low. Projects was in the process of developing a plan for changing out the pressure switches identified in the SPR. The SPR was not backlogged as an inactive item; however, the documented potential for a failure did not place this as a top priority item.

This investigation considered the awareness of the failure history of the pressure switches and the corrective actions taken by involved personnel and concluded that the steps taken for resolution of the problem were within station policy. However, if additional measures had been taken, such as more detailed inspection of the pressure switches and more emphasis being place
on ensuring the replacement of critical pressure
switches during the U2EOC4 outage, this incident may have been avoided.

Upon the CFPT 2A trip, a turbine runback was initiated with a runback rate of approximately 20% per minute. The programmed turbine runback is set to runback quickly for one second, delay for five seconds, runback quickly again for one second, etc. However, during the incident, the turbine runback was delayed for approximately 6-7 seconds. A subsequent investigation revealed that the delay was due to the CROs operating with a difference between the turbine "load limiting limiter" switch and the "load set" signal. When the turbine runback initiated, it took 6-7 seconds for the runback to move the "load set" signal below the "load limiting limiter" setpoint; the point where actual megawatts are

decreased or "shed". CROs operating with a difference between the "load limiting limiter" switch and the "load set" signal is a normal operating practice used by operators to restrain the actual megawatts from oscillating or "hunting". This megawatt oscillation problem is an inherent characteristic of the Turbine Control (EHC) System. As a corrective action, Operations Training will review and discuss this incident and the lessons learned with operations personnel during the next requalification sessions.

Another aspect of the turbine runback was the turbine's failure to stop at the prescribed setpoint of approximately 70% load. Based on review and evaluation of past incidents which rapid turbine runbacks have occurred, MES has found that a S/G "swell" (approximately a 2-5% increase in level) occurs after termination of the runback; a positive effect in terms of avoiding S/G low low level conditions. However during this incident, the turbine continued to runback until the turbine tripped upon the Rx trip. The root cause for the excessive runback was determined to be failure of 2SMPS5217 (Turbine 1st stage pressure). A subsequent investigation discovered that the pressure switch was full of water due to a ruptured diaphragm. This is the same type of switch and failure that caused the CFPT 2A trip. This switch was also replaced per W/R 3201MES.

In conjunction with the turbine runback, S/G levels and NC system T-AVE were rapidly decreasing. At approximately 1659 hours, 2D S/G reached its Low Low level setpoint causing a Rx and turbine trip and an automatic start of the CA motor driven pumps. Subsequently, 2C S/G reached its Low Low level setpoint which satisfied the auto start logic for the CA turbine driven pump. Finally, at approximately 1700 hours, a CF Isolation occurred due to the Rx trip and NC T-AVE decreasing below 564 degrees F. The CA system response was proper in that all CA valves and pinups auto started and functioned properly. However, the Performance group's evaluation of the CA system response to the transient did identify an anomalous behavior in CA motor driven pump 2B flow to S/Gs C and D. The flow start time was delayed by approximately 15 seconds. Performance of the CA System Flow Verification Test (PT/2/A/4250/06B) on October 8, 1990 revealed that when both CA pumps were started simultaneously, no delay in pump 2B startup occurred. Performance (PRF) and Maintenance Engineering Services (MES) then postulated that the delay could be due to voided suction piping, voided discharge piping, or hang up of the suction check valve (2CA-10). However, it was concluded that discharge piping voiding was not possible due to the amount of discharge piping that would have to be voided to cause such a delay. A hung suction check valve (2CA-10) or voided suction piping was disregarded due to the fact that no degradation was observed in pump performance during the OPS Pump Head and Valve Verification Test, along with Vibration Monitoring by MES performed on October 8. As corrective actions, PRF and

MES will perform, on a monthly basis (through January 31, 1991), the CA pump 2B IWP test in conjunction with MES vibration testing to monitor pump performance. In addition, MES will perform a motor amperage comparison of CA pumps 2A and 2B will be performed in an attempt to detect any shaft binding or motor problems with pump 2B. CA flow to all S/Gs was properly initiated within the Tech Spec requirement of one minute.

A review of the Operating Experience Program (OEP) database for the past 24 months identified two previous incidents where an Equipment Failure of a feedwater system component resulted in a manual Rx trip. LERs 414/89-017 and 414/89-022 involved manual Rx trips due to failure of a gasket on a main feedwater system valve positioner control air manifold due to inadequate torque on the mounting screw and/or marginal gasket design and less than adequate installation. Corrective actions included a revision to the instrument procedure for more adequate torque requirements, incorporation of CF valves inspections in the preventive maintenance program, and resolutions for discrepancies identified during the post-trip emphasizes the need to improve the reliability of the feedwater system and is considered a recurring problem per Duke Power Company Nuclear Safety Assurance guidelines.

CORRECTIVE ACTION

IMMEDIATE

1) CROs verified per control room instrumentation that CFPT 'A' had tripped on high discharge pressure and dispatched an operator to investigate the trip locally.

2) CROs verified that a turbine runback was initiated.

3) CROs referred to AP/2/A/5500/06 (Loss of Feedwater) and AP/2/A/5500/03 (Load Rejection) procedures for guidance and performed the required actions.

4) CROs took manual control of CFPT 'B' in an attempt to obtain control of S/Gs inventory.

SUBSEQUENT

1) CROs verified per control room instrumentation that a Reactor and main turbine trip had occurred.

2) CROs referred to EP/2/A/5000/01 (Reactor Trip/Safety Injection) procedure for guidance and performed the required actions.

3) Per guidance in EP/2/A/5000/01 (No Safety Injection occurred), CROs referred to EP/2/A/5000/01A (Reactor Trip Response) and performed the required actions.

4) CROs referred to AP/2/A/5500/02 (Turbine Generator Trip) procedure for guidance.

5) CROs isolated various steam drain valves and dispatched an operator to startup both AEBs in an attempt to minimize the cooldown.

6) Catawba initiated an investigation of the CFPT 'A' and Reactor trip to determine the root cause(s).

7) Instrument and Electrical (IAE) per W/R 47417OPS investigated the reason for CFPT 'A' trip on high discharge pressure. IAE discovered water in 2 of 3 pressure switches due to ruptured diaphragms.

8) Per W/R 3201MES, MES determined that the "Load Set" switch was at a higher setting than the "Load Limiting Limit" switch. Therefore, the turbine control valves movement was delayed (approximately 6 seconds) until the "Load Set" setpoint was dropped below the "Load Limiting Limit" setpoint; thus causing a delay in the turbine runback.

9) Per W/R 3201MES, MES investigated and determined that pressure switches (2SMPS217 and 5212) which terminate the turbine runback at the desired load setpoint failed due to water infiltration. The pressure switches were replaced.

10) Performance reviewed the CA system response during transient (15 seconds delay in CA pump 2B flow) and performed flow tests which determined no problems which would prevent restart of the unit.

PLANNED

1) Catawba will continue the replacement of all Custom Controls polymide (Kapton) diaphragm pressure switches used in critical applications in the plant. Emphasis will be given to those switches which have unit trip potential. (Reference Design

Study CNDS-0194 and CNPR-05122).

2) Operations Training group will review and discuss this incident with with Operations shift personnel during the next Requalification Training.

3) On November 14, 1990, a post-LER review of this incident was held to discuss and resolve several questions which were raised following the submittal of the LER. The conclusions from this report were as follows:

a) Unit 2 CF pumps operates at approximately 10 psi higher pressure than Unit 1 CF pumps (225 psid versus 215 psid) which corresponds to approximately 120 rpm higher speed.

b) Modifications made during the Unit 2 EOC3 outage resulted in the CF bypass valves being opened wider. This in turn resulted in the CF regulating valves being slightly less open during the transient.

c) Prior to this transient, the 2A CF pump was operating at approximately 300 rpm greater speed than the 2B CF pump. From past experience, it has been found that the "lead" pump has been the one which trips which worsens the transient and lessens the survivability of this type of transient.

d) Termination of a rapid turbine runback at the proper setpoint (70%) usually results in a S/G "swell" (2-5% level increase), a positive effect in terms of avoiding S/G low level conditions.

e) During this fuel cycle, the "D" NC loop has been "hotter" than the others. The "hotter" NC loop attributed to the more rapid inventory loss from the 2D S/G.

Operations Training group will review, with respect to the impact on the transient experience after the loss of one CF pump, the conclusions drawn from the post LER review meeting in order to incorporate these conclusions in their classroom lectures and lesson plans.

4) MES will develop Standing Work Requests (SWRs) to inspect monthly all pressure switches identified in SPR CNPR-05122 until

they have been replaced with a new model.

SAFETY ANALYSIS

The
ransient experienced during this incident is bounded by the FSAR analysis described in Section 15.2.7, Loss of Normal Feedwater Flow. The analysis states that a loss of normal feedwater results in a reduction in capability of the secondary system to remove heat generated in the reactor core. If an alternate supply of feedwater were not supplied to the plant, core residual heat following Reactor trip would heat the primary system water to the point where water relief from the pressurizer would occur, resulting in a substantial loss of water from the NC system. However, the plant is tripped on low steam generator level well before the steam generator heat transfer capability is reduced; therefore, the primary system variables should not approach a DNB condition.

The analysis also describes plant events and conditions upon a loss of normal feedwater (assuming main feedwater pumps and valves malfunction and steam dump valves are not available) which are a steam pressure rise following the trip which is handled by use of the S/G Power Operated Relief Valves (PORVs) and/or safety valves, a Rx trip on low low narrow range level in any S/G, and an auto start of the CA system to provide and recovery inventory in the S/Gs to remove decay heat in order to prevent heatup and overpressurization of the NC system.

During this incident, CFPT 2A tripped on an erroneous high discharge pressure as its trip logic was satisfied. The CFPT 2B remained inservice providing maximum flow to S/Gs. Upon the loss of CFPT 2A, a turbine runback was initiated after a delay of approximately six seconds. S/G levels and NC T-AVE were rapidly decreasing. Subsequently, 2D S/G reached its low-low level setpoint resulting in a Rx and turbine trip.
In addition, an auto start of the CA System (motor and turbine driven pumps) was initiated as their auto start logic was satisfied.
Ultimately, a CF Isolation was initiated as the NC T-AVE decreased to less than 564 degrees F. Upon review of this incident, all systems initiated to mitigate the transient functioned properly with the exception of the 15 second delay in start of CA flow to S/Gs C and D. CA flow was delivered to S/G C and D within .the bounds assumed in the referenced FSAR analysis and within the time period (1 minute) required by Technical Specifications. There were no actuations of Atmospheric Dumps, S/G PORVs, or S/G safety valves during the transient. Furthermore, S/G inventory was maintained well above critical levels and excessive NC system heatup and overpressurization was prevented.

However, anomalous behavior of the Turbine Control System and the responsiveness of the CA System during the transient were noted for further evaluation. The systems' ability to meet their Technical Specification and design requirements were not affected.

The health and safety of the public were unaffected by this incident.

ATTACHMENT 1 TO 9101020270 PAGE 1 OF 1

Duke Power Company (803) 831-3000
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DUKE POWER

December 20, 1990

Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Catawba Nuclear Station
Docket No. 50-414
LER 414/90-13, Revision 1

Gentlemen:

Attached is Licensee Event Report 414/90-13, Revision 1, concerning MAIN FEEDWATER PUMP TRIP DUE TO EQUIPMENT FAILURE RESULTING IN A REACTOR AND
MAIN TURBINE TRIP.

This event was considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

J. W. Hampton
Station Manager

ken\LER-NRC.JWH

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